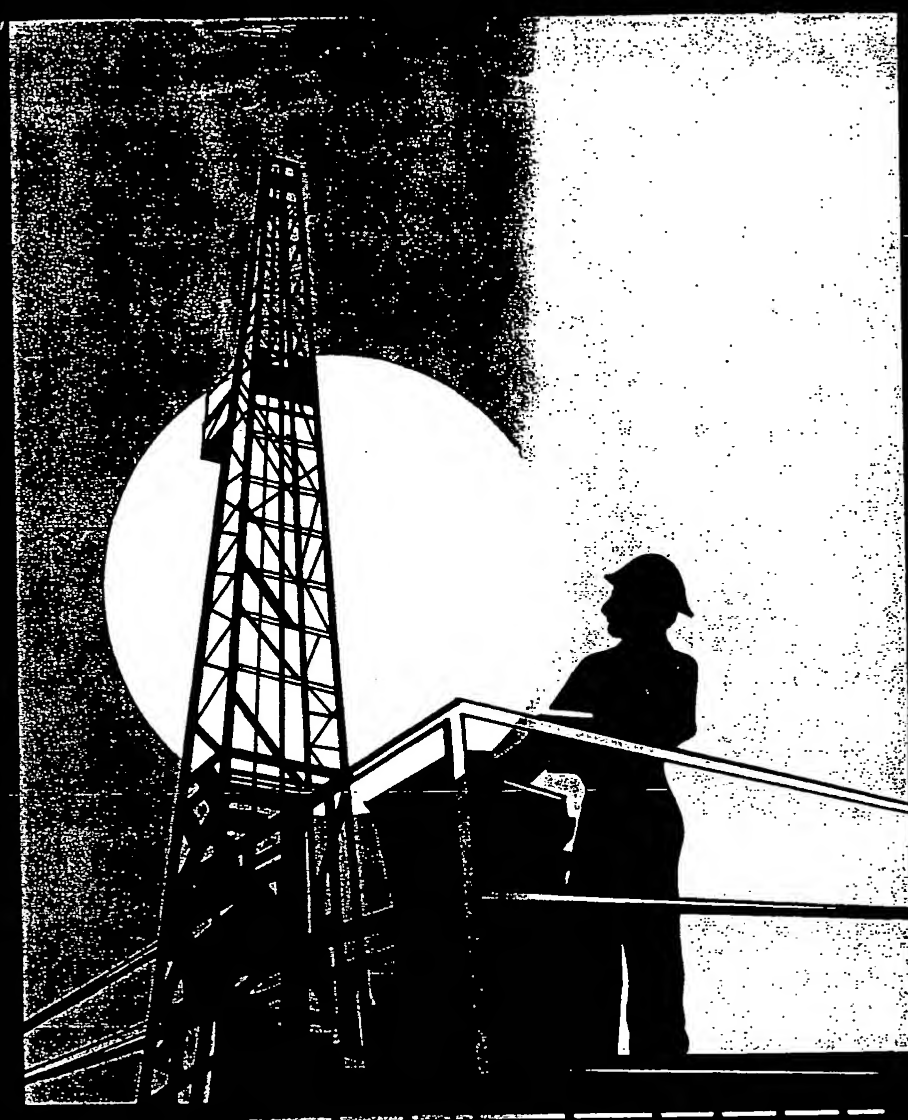

Drilling Engineering

A Complete Well Planning Approach

Neal J. Adams
assisted by Tommie Charrier

Drilling Engineering

A Complete Well Planning Approach

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tension device that connects the elevators to the hook on the traveling block, allows space for other tools connected to the top of the drillstring. The elevators must conform to specifications in API Spec. 8A, "Drilling and Production Hoisting Equipment."

Slips. The slips secure the drillstring in the rotary table during each connection. The outer diameter of the slips has a taper of 9° 27′ 45″. The inner diameter has a set of jaws for "biting" into the pipe. The slips should never be set while the drillstring is being lowered because the jaws will bite deeply into the pipe and the inertia of the pipe may cause pipe stretching or "bottlenecking" at the point where the slips were set.

Safety Clamps. Drill collar slips are not as effective at holding the string since the collars usually do not have upsets. As a safety measure, clamps are secured around the collars above the slips to prevent the collars from sliding through the slips. The clamps require a small amount of additional effort from the rig crew during each trip.

Tongs. The pipe or collar is made up or broken out with the tongs (Fig. 16–57). Backup tongs grip the pipe, while lead tongs apply torque to the pipe. The tongs should be installed on the rig so that the tong body is perpendicular to the pulling line at the optimum torque point. If the perpendicular pull does not occur, the torque gauges on the tongs do not provide an accurate estimate of torque being applied to the pipe.

Blowout Preventers

When primary control of the well has been lost due to insufficient mud hydrostatic pressure, it becomes necessary to seal the well to prevent an uncontrolled flow, or blowout, of formation fluids. The equipment that seals the well is the blowout preventer (BOP). It consists of drillpipe blowout preventers designed to stop the flow through the drillpipe and annular preventers designed to stop flow in the annulus. The drilling rig must be evaluated to determine if its BOP equipment meets the minimum specifications. Otherwise, it is common to rent the proper equipment.

Annular Blowout Preventers. The blowout preventer stack controls the flow of fluids in the annulus and may be a composite of several types of annular blowout preventer elements. Some, but not all, of these elements may include bag preventers, blind and pipe rams, and drilling spools. (Each type of element will be discussed, with actual BOP stack design criteria presented in later sections.) The annular preventer is also known as the spherical or bag-type preventer.

Annular (Spherical) Preventers. The first preventer normally closed when shutin procedures are initiated is the annular preventer. The four basic segments of the annular preventer are the head, body, piston, and steel-ribbed packing element (Fig. 16–58). When the preventer's closing mechanism is actuated,

Fig. 16–58 Annular com

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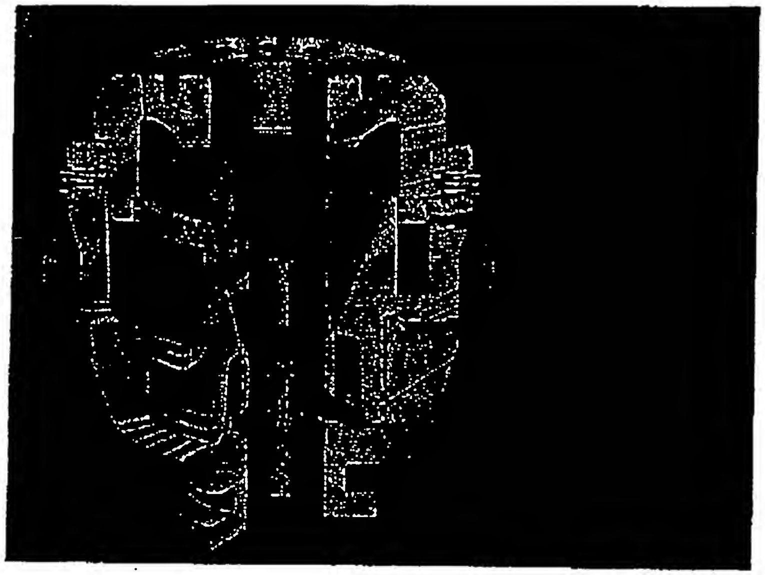

Fig. 16–58 Annular components (Courtesy Hydril Co.)

hydraulic pressure is applied to the piston, causing it to slide upward and force the packing element to extend into the wellbore around the drillstring. The preventer element is opened by applying hydraulic pressure in a manner that slides the piston downward and allows the packing to return to its original position.

Ram Preventers. Unlike the operational manner of the annular preventer, the ram preventers seal the annulus by forcing two elements to make contact with each other in the annular area. These elements have rubber packing seals that affect the complete closure. Other than the sealing mechanism, ram blowout preventers (pipe, blind, and shear) differ greatly from annular preventers in that each type and size of ram has one function and cannot be used in a variety of applications (Fig. 16–59).

For example, ram bodies with 4½-in. rams will seal on 4½-in. pipe and will not seal with any other size of pipe, nor will they seal without pipe in the well. (The exception to this is the variable bore ram.) Ram preventers, however, are generally considered to be more reliable in high pressure service as well as more easily serviceable and requiring less vertical space in the BOP stack.

Ram bodies are universal; they will accept either blind ram elements or pipe ram elements. Also, units are available that are comprised of single, double,

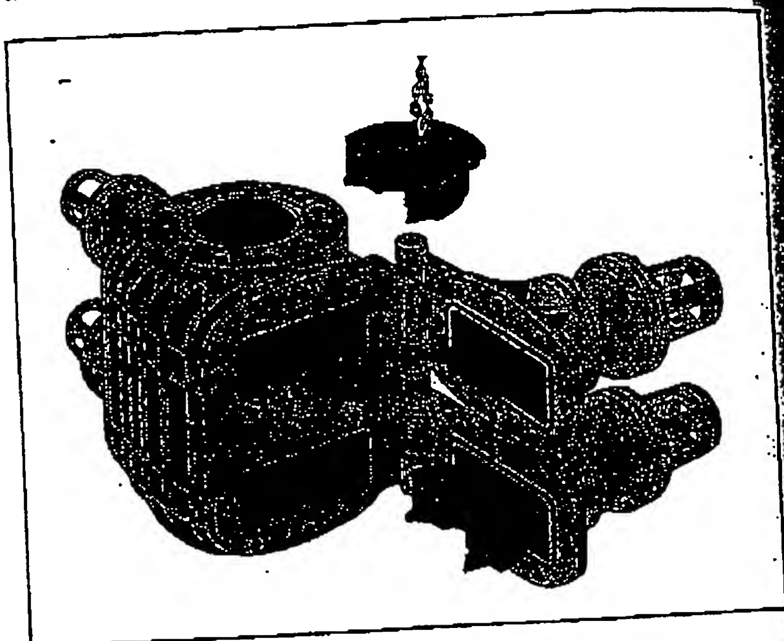

Fig. 16-59 Ram-type preventer (Courtesy N.L. Shaffer)

or even triple ram bodies. In the multiple-unit ram bodies, any combination of pipe and blind ram elements may be used.

Caution must be given to ram size selection when aluminum drillpipe is used. This type of pipe has a tube in the middle section that is slightly smaller than the tube near the tool joint. Regular 4½-in. pipe rams will seal on the middle tube section of 4½-in. aluminum pipe but not near the tool joint, as could be done with steel pipe. The shutin procedures must be planned accordingly to account for this irregularity.

Blind rams seal the well if pipe is not in the hole. The element is flat-faced and contains a rubber section. The rams are not designed to effect a seal when pipe is in the hole, although occasionally the pipe will be cut if the blind rams are accidentally closed. Precautions should thus be taken with the blowout preventer control panel to ensure the blind rams cannot be accidentally closed.

Shear rams are specially designed blind rams. As the word "shear" indicates, this type of ram will seal if pipe is in the hole by shearing, or cutting, the pipe and sealing the open wellbore. Since this type of action drops the drillstring, a set of pipe rams may be installed below the shear rams and a tool

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Drilling Spools. If blowout p
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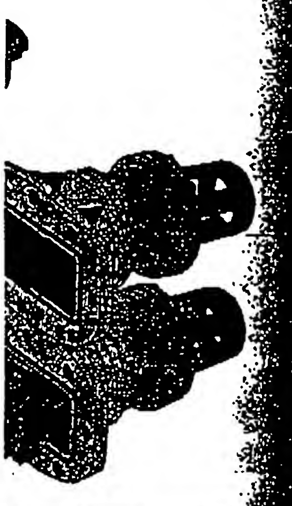

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joint set on the pipe rams before the shear rams are activated. When the shear rams are installed in conventional ram bodies, booster power units and larger bonnets may be necessary for efficient operations.

Drilling Spools. If blowout preventer elements without built-in mud exit lines are used, it becomes necessary to install a drilling spool, which is a connector placed within the BOP stack to which mud access lines (choke and kill lines) are attached. The spool may be studded, flanged, or clamp-on connected and should meet the following API requirements:

1. Have a working pressure consistent with that of the remainder of the blowout preventers
2. Have one or two side outlets, no smaller than 2 in. in diameter, with a pressure rating consistent with the BOP stack
3. Have a vertical bore diameter at least equal to the maximum ID of the innermost casing. If the spool is to pass slips, hangers, or test tools, the bore should be at least equal to the maximum bore of the uppermost casinghead or BOP stack

Fig. 16–60 illustrates a flanged drilling spool with two side outlets.

Casing head. The basis of all stacks and usually the first component installed is the casinghead. The head can be equipped with flanged, slip-on and weld, or threaded connections for attachment to the casing and the preventer stack, and can have threaded or open-faced flanged side outlets. The casinghead should meet at least the minimum API requirements as follows:

1. Have a working pressure rating that equals or exceeds the maximum anticipated surface pressure to which it will be exposed
2. Equal or exceed the bending strength of the outermost casing to which it is attached
3. Have end connections of mechanical strength and pressure capacity comparable to corresponding API flanges or to the pipe to which it is attached
4. Have adequate compressive strength to support subsequent casing and tubing weight to be hung therein

Fig. 16–61 is an example of a casinghead with threaded lower connections and flanged upper connections.

Diverter Bags. In certain cases, proper well control procedures demand that a kick not be shutin but rather be blown out in a controlled manner away from the rig. These blowout diversion procedures do not require a full blowout preventer stack; instead, a diverter bag is used, which is a relatively low working pressure tool. Fig. 16–62 illustrates a diverter stack in which a spherical preventer is used as the diverter bag.

Rotating Head. The primary function of an annular preventer is to provide pressure control while allowing a small amount of pipe movement. Occasionally, a tool is needed that will provide greater amounts of pipe movement flexibility

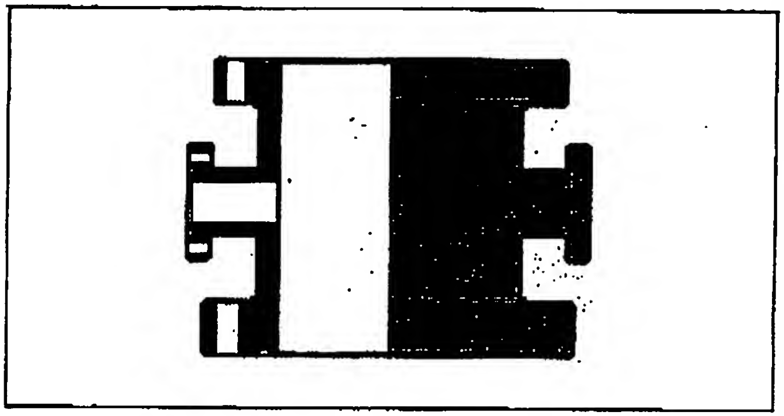

Fig. 16–60 Drilling spool (Courtesy W-K-M)

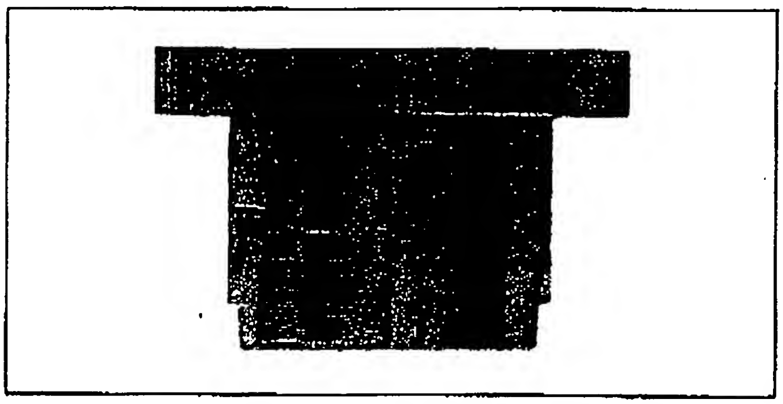

Fig. 16–61 Casinghead (Courtesy Cameron Iron Works Inc.)

at lower service pressures. The rotating head serves this purpose. Rotating heads (Fig. 16–63) have been used in air and gas drilling, controlled pressure drilling, and reverse circulation operations with well pressures to 2,000 psi and at rotating speeds to 150 rpm. When used in controlled pressure drilling, the head allows the use of lighter muds with increased penetration rates and reduced swabbing. The head also maintains the gas in a kick under pressure to reduce its volume.

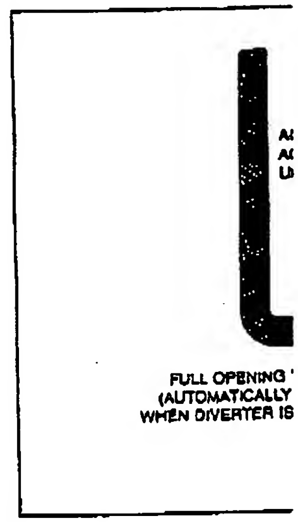

Fig. 16–62

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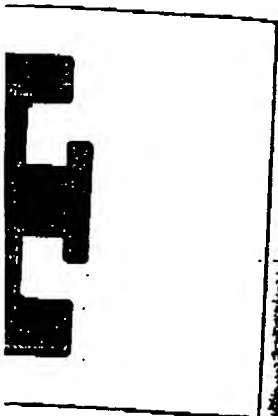

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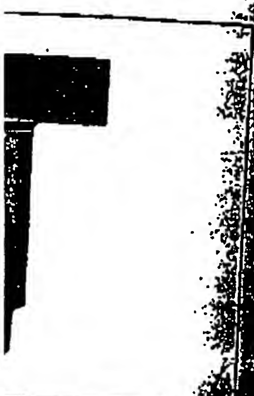

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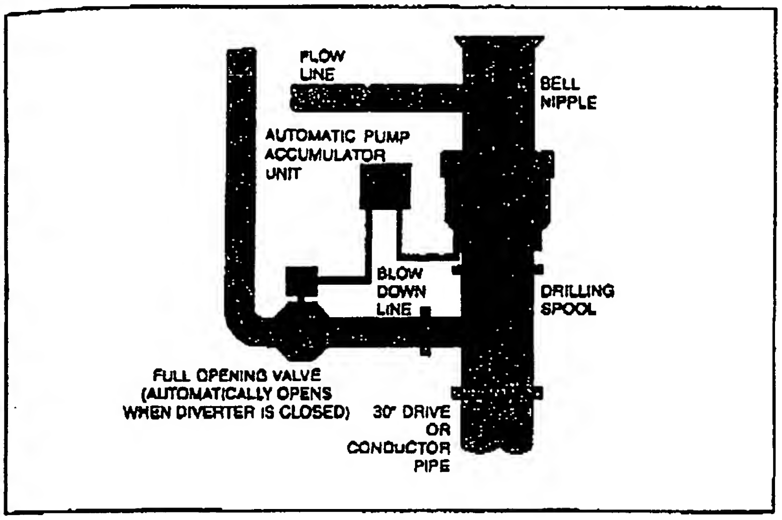

Fig. 16–62 Diverter stack (Courtesy Hydril Co.)

Choke and Kill Lines. In well killing operations, it generally is necessary to circulate fluid down the drillpipe, up the annulus, and through an exit at the surface. The lines that are attached to the blowout preventers to provide this exit are termed choke and kill lines. The choke line carries the mud and kick fluid from the BOP stack to the choke device. The kill line is a backup choke line. The choke and kill lines may be used to pump mud directly into the annulus if necessary, although the kill line usually performs this function.

The choke and kill lines may be attached to several members of the BOP stack. These lines could be attached to the outlets of the drilling spool shown in Fig. 16–60, or they could be attached directly to the BOP, as indicated in Fig. 16–59. Only under extreme circumstances, and never preferentially, should the choke and kill lines be attached to the casinghead, casing spool, or below the lowermost set of rams. (See the section on preventer stack design for a further explanation.)

The choke and kill lines should meet a number of requirements. Some, but not all, are as follows:

1. The pressure ratings of these lines should be consistent with the blowout preventer stack.
2. The lines should meet all minimum BOP testing requirements.
3. The lines should have a consistent ID to minimize erosion at the point of diameter changes.

4. The number of angular deflections within the lines should be minimized. If the lines must make several angular changes between the stack and the choke manifold, it may be advisable to use tees and crosses to absorb the turbulent erosion effects at these points.

Drillpipe Blowout Preventers. The prevention of blowouts through the drillpipe is an important facet of well control. When a kick occurs, the influx fluid will generally enter the annulus due to the direction of drilling fluid flow during normal drilling circulation. However, if the kick fluid should enter the drillpipe, the shutin drillpipe pressures will be greater than normal kick conditions due to the vertical column of mud that will be displaced by a relatively small volume of influx fluid. As a result, the selection and utilization of drillpipe BOP equipment is essential for proper kick control.

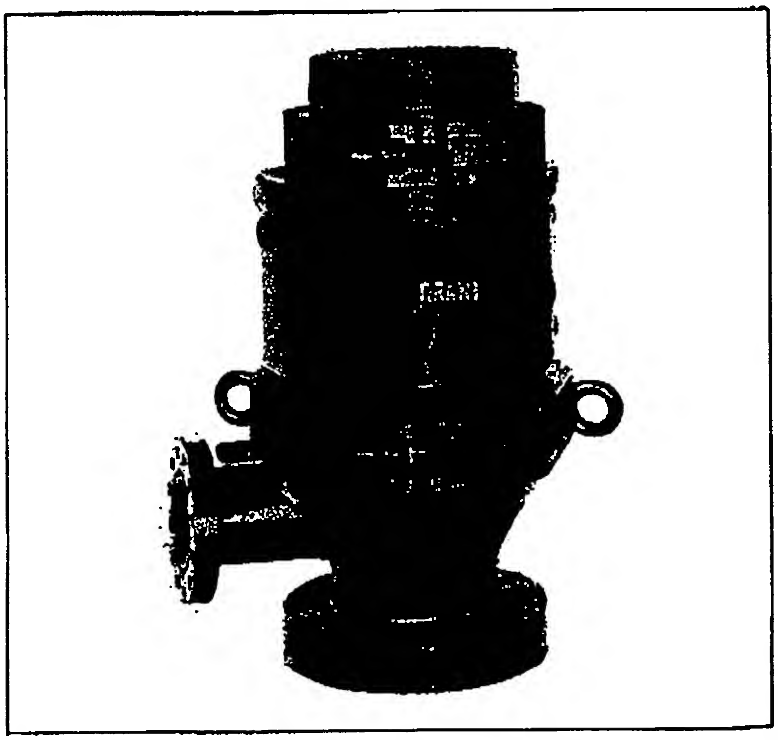

Fig. 16–63 Rotating head (Courtesy Grant)

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Fig. 16–64

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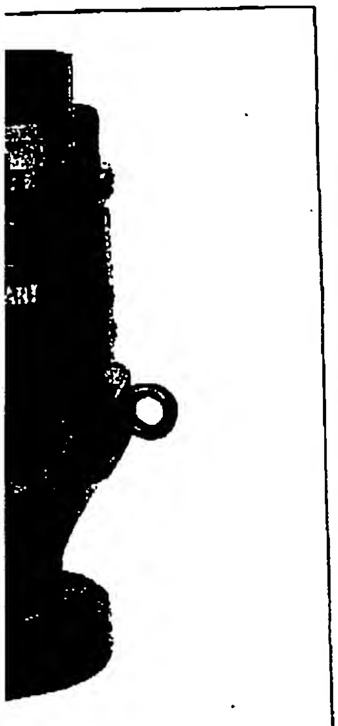

(Courtesy Grant)

Several tools contain drillpipe pressures during kicks. The primary tool is the kelly and its associated valves, such as the kelly cocks. When the kelly is not in use, drillstring valves are necessary to control the pressures. These valves may be automatic or manual control and may be a permanent part of the drillstring or installed when the kick occurs.

Kelly and Kelly Cock. The kelly, which imparts rotary motion to the drillstring, is the connection between the drillstring and the surface drilling equipment. Valves are generally placed above and below the kelly to provide pressure protection for the kelly and all the surface equipment. These valves, called kelly cocks, should be of a pressure rating consistent with the remainder of the drillstring and should be capable of sustaining the wear and hook load required of the hoisting equipment (Fig. 16–64).

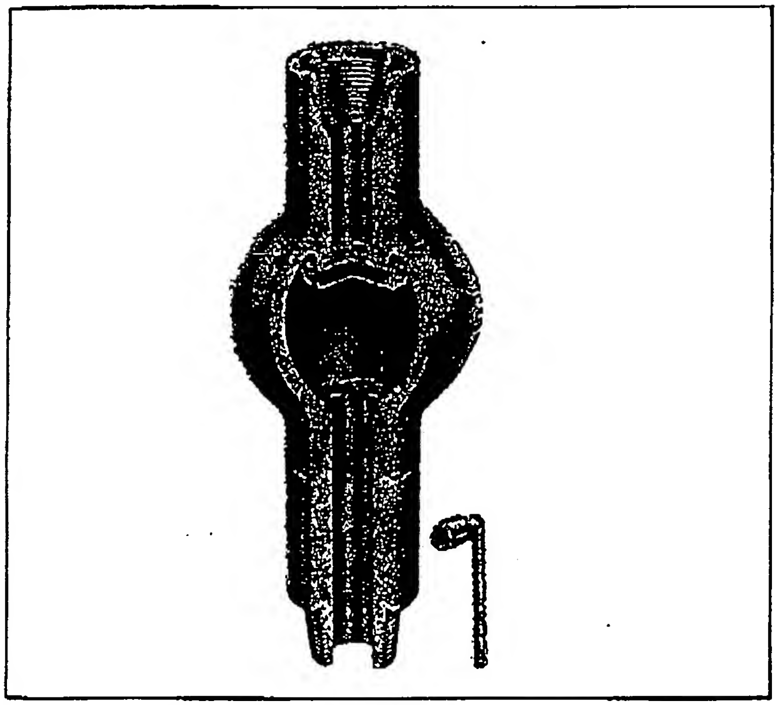

Fig. 16–64 Kelly cock (Courtesy Omsco)

Automatic Valves. An automatic closure, or float valve, in the drillstring will generally allow fluid movement down the drillpipe but will not allow upward flow. The valve may be the flapper type, a spring-loaded ball, or the dart type and may be permanent or pump-down installed. Although the valve prevents drillpipe blowouts, it is often used to minimize flowback during connections or to prevent bit plugging.

There is a disadvantage relative to well control when a float valve is installed in the drillstring because the basis of proper kick killing procedures is dependent on a drillpipe pressure determination. Since a direct reading of static drillpipe pressures is impossible with a conventional float valve, alternative pressure reading procedures that are more complex must be implemented. This problem can be circumvented if a flapper valve is used that has small, built-in fluid ports to allow pressure buildup at the surface while still preventing a blowout.

Manual Valves. The manual valve, commonly called a full-opening safety valve, is usually installed on the drillpipe after a kick occurs when the kelly is not in use. The advantage of a manual valve is that it can be in the open position when it is stabbed on the drillpipe and will thus minimize the effect of upward moving mud lifting the valve. The mud will pass through the valve during the stabbing, after which the valve can be closed.

Automatic valves, in some types, can be locked in the open position to achieve this stabbing feature. Closing of the manual valve requires that a wrench be kept on the rig floor, accessible to the rig crew (Fig. 16–65).

The manual valve has one feature that makes it advantageous over the automatic valve in certain applications. When open, the manual valve has a nonobstructed orifice, whereas the automatic valve locked in the open position has the sealing mechanism (flapper, ball, or dart) serving as an obstruction. Should it become necessary to do any wireline work, the manual valve can be opened and will allow passage of any tools that have a diameter smaller than that of the inner valve. This cannot be done with the automatic valve.

Blowout Preventer Stack Design. There are several considerations in designing an arrangement of annular blowout preventers. Among these are pressure design, component selection and arrangement, subsea-related variations, and diverter systems.

Pressure Design. Several well-founded viewpoints relate to the pressure requirements that preventer stacks should meet. Some, but not all, of the arguments are that the working pressure needs to be no greater than the burst strength of the exposed casing string, formation fracture pressure of the shallowest exposed zone, or a predetermined maximum allowable surface casing pressure. However, all of these guidelines may present serious problems when applied in severe well control situations.

The most common of these guidelines is that the preventers need to be no stronger than the casing string to which they are attached. The inherent fallacy

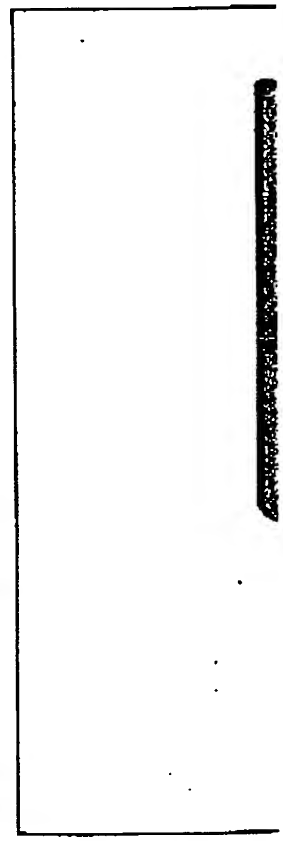

Fig. 16–65 Manua

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The safest procedure
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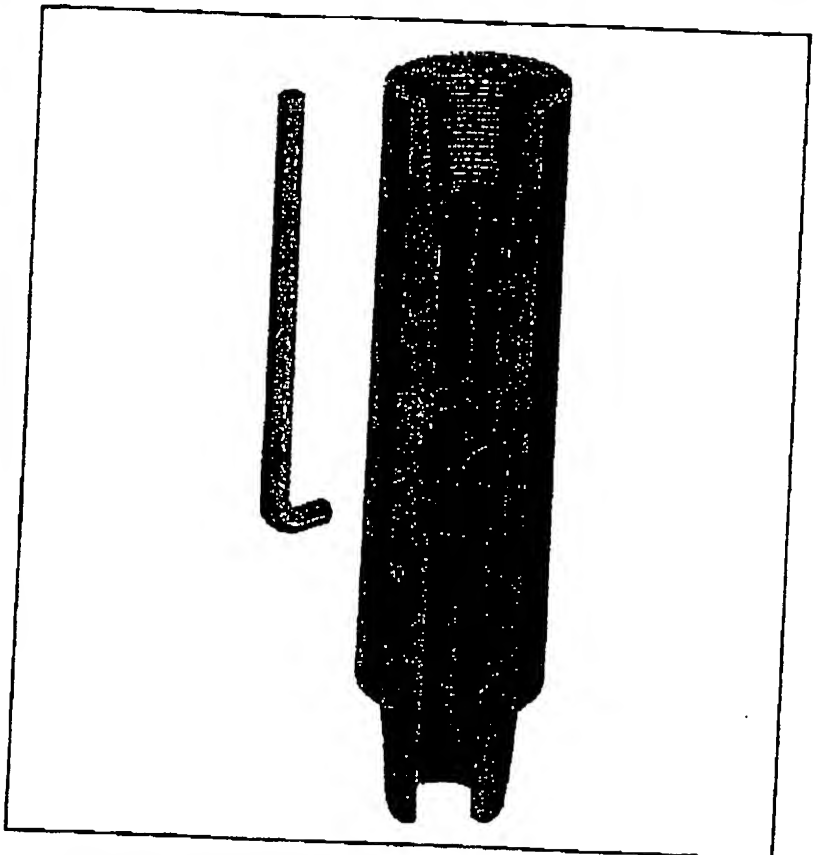

Fig. 16–65 Manual full-opening safety valve (Courtesy Omsco)

with this guideline is that it assumes the casing string has been properly designed to withstand kick-imposed stresses. This is quite often not the case. It would follow that if the casing is improperly designed, the preventer pressure rating is also improperly designed.

The safest procedure for designing preventer pressure ratings is to ensure that the preventers can withstand the worst pressure conditions possible. These conditions occur when all drilling fluids have been evacuated from the annulus and only low-density formation fluids such as gas remain. This procedure is illustrated in Example 16.9.

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